Section 6
Santee Cooper 2020 IRP Development

Santee Cooper developed its 2020 IRP with consideration of future loads, existing resources, resource needs, future resource options, and projected costs for the Santee Cooper system. Through this process, Santee Cooper evaluated potential long-term resource plans to identify plans that reliably and economically meet future loads while providing for flexibility, resource diversity, technological innovation, improved efficiency, and reduced environmental impacts. The following section provides a detailed discussion of the methodology and assumptions utilized for the Santee Cooper 2020 IRP.

Methodology

Santee Cooper has prepared its 2020 IRP utilizing generally accepted utility practices, including the use of overarching principles and objectives, realistic projections of economic and market conditions, historical operating characteristics for existing resources, industry-based assumptions for future resource alternatives, load forecasts developed using industry-standard techniques, identification of future power supply needs, integration of cost-effective DSM programs, evaluation of renewable and energy storage resources, screening of potential resource sites, simulation of resource dispatch, optimization of resource expansion plans, evaluation of coal resource retirements, and evaluation of resource plan sensitivities to changes in load, market, and regulatory conditions.

Santee Cooper has utilized an industry-accepted generation simulation and optimization software model to perform its resource expansion evaluations to identify a least-cost portfolio of future resources under a set of Base Case assumptions and under multiple sensitivity case assumptions reflecting changes in forecast load growth and fuel and power prices. To assure that resource plans are sufficiently flexible to address potential carbon regulations, a sensitivity case depicting a CO_2 tax and multiple portfolios for varying assumptions regarding retirement of Santee Cooper coal resources were investigated. Additionally, sensitivity cases were prepared to analyze the impact of lower levels of solar resource implementation.

Figure 6-1, below, provides a depiction of the overall process utilized by Santee Cooper when developing its 2020 IRP.

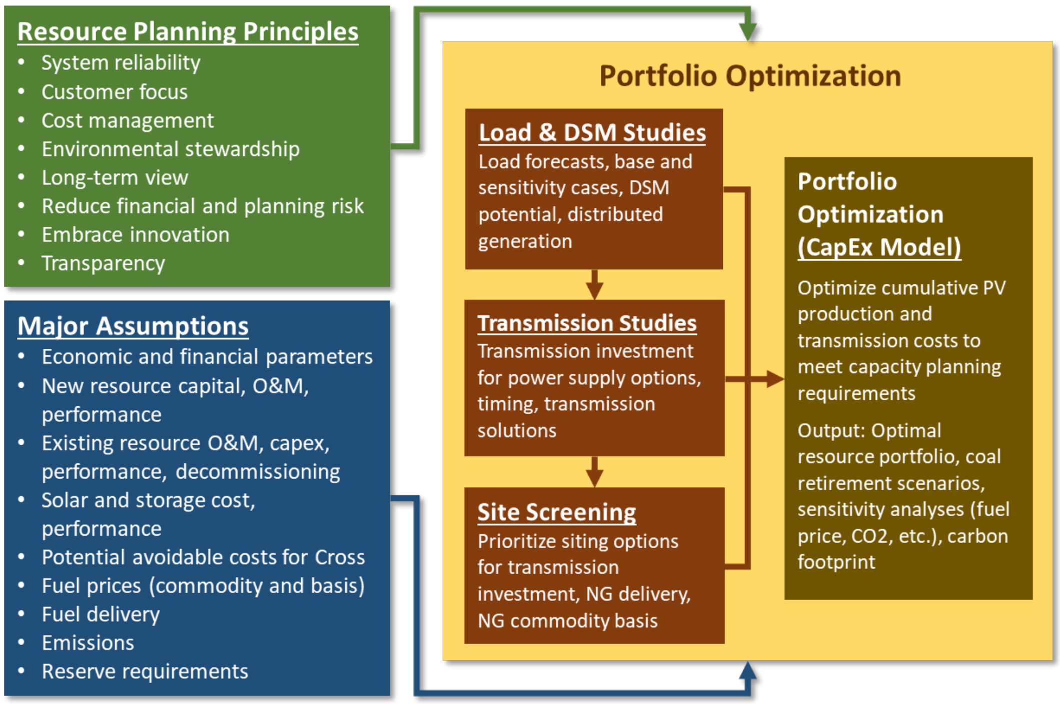

Figure 6-1: Santee Cooper IRP Process

Capacity Expansion Model

The IRP dispatch and capacity expansion analysis was performed by Santee Cooper using the Capacity Expansion (CapEx) resource expansion optimization software model licensed by Hitachi ABB Power Grids, a leading vendor of power system simulation software applications that are widely used across the electric utility industry. CapEx is a PC-based software model capable of simulating hourly generating resource dispatch and evaluating future resource expansion plans using a mixed integer linear programing technique to identify a least-cost portfolio of resources, including future resource options identified by the user. CapEx simulates resource dispatch utilizing representative typical days and user-defined time periods.

For the 2020 IRP, the Santee Cooper electric system was modeled as a stand-alone system, with Santee Cooper generating resources and firm purchase power arrangements dispatched to meet the Santee Cooper load and wholesale sales obligations. Santee Cooper's projected loads and wholesale obligations modeled for the 2020 IRP include Santee Cooper retail loads; sales to Central; partial requirements sales to the municipalities of Seneca, South Carolina, Waynesville, North Carolina, and Piedmont Municipal Power Agency; and other firm wholesales sales contracts, each with specific terms. Additional information on retail load and wholesale sales obligations are provided in Section 4.

Non-firm wholesale economy market purchases were simulated concurrently with the dispatch of other Santee Cooper resources, with price and import characteristics as described below. Non-firm wholesale economy market sales were not simulated as part of the IRP evaluation to eliminate the chance that the CapEx model might identify future expansion resources that rely on benefits of speculative market sales.

Portfolio Evaluation

Santee Cooper performed resource portfolio simulations in CapEx under multiple assumptions for coal resource retirements and generation expansion options (as described in more detail below). Common to each of the portfolios evaluated is the adoption of resource retirements and resource additions targeted to achieve broader planning objectives of Santee Cooper to diversify its resource portfolio, reduce reliance on coal generation, reduce greenhouse gas emissions, and increase use of renewable and storage technologies.

Santee Cooper Power Supply Roadmap

The Santee Cooper 2020 IRP assumes certain fixed resource retirement and resource expansion assumptions as part of all resource plans evaluated. For each of the expansion plans evaluated in CapEx, the 2020 IRP reflects the following resource additions and retirements.

- Retire the Winyah coal plant through a phased approach, idling Unit 4 by the winter of 2020/2021, idling Unit 3 by the Winter of 2021/2022, and fully retiring all four Winyah coal units by 2027.
- Add quick-start resources to ensure system reliability by installing 20 megawatts of diesel-fired reciprocating internal combustion engine (RICE) generating units in 2022 prior to idling Winyah Unit 3. The RICE units, already owned by Santee Cooper at the V. C. Summer site, will be installed at a new site near the Santee Cooper Conway substation.
- Add 500 megawatts of new solar resources by 2023 through an ongoing request for proposals (RFP) process jointly undertaken with Central, and plan for an additional 1000 megawatts of solar resources by 2032.[6]
- Add 200 megawatts of utility-scale battery storage to the Santee Cooper system in phases (50 megawatts by 2026, 100 megawatts by 2033, and 200 megawatts by 2036).[7]
- Implementation of demand response programs, consisting of direct load control, voltage control, and other measures, to avoid approximately 85 megawatts of winter peak load by 2027, increasing to 106 megawatts by 2034 (representing the total combined impacts for Santee Cooper and Central).

Some of these resource retirement and addition assumptions reflect resource decisions and plans that are already being implemented by Santee Cooper, such as the retirement of the Winyah Generating Station, installation of quick-start resources at a site near the Conway substation, and the

[6] Solar resources have the potential to provide a low-cost, low environmental impact resource option for the Santee Cooper system and, as such, have been included in the long-term Santee Cooper resource plans. However, Santee Cooper intends to conduct additional analyses to evaluate the cost and reliability of integrating and operating solar resources before formal decisions regarding solar implementation beyond 500 megawatts are made.

[7] Phased implementation of battery storage will allow Santee Cooper to take advantage of market trends toward lower costs and to gain industry insights and experience on utility-scale battery operation.

ongoing RFP solicitation for 500 megawatts of solar resources. Other resource addition assumptions, including energy storage, additional solar, and demand response, reflect strategic choices in Santee Cooper's long-term resource roadmap. The timing for implementing these resources takes into consideration anticipated improvements in cost and technology and the need for additional studies.

Alternative Retirement Portfolios

The IRP analysis was performed in a manner that provided for the identification of potential least-cost resource portfolios under representative scenarios for coal resource retirements. Under each coal retirement portfolio, a resource expansion optimization analysis was performed under the Base Case assumptions and under various sensitivity case assumptions (see below).

- **Retire Winyah Portfolios** – As discussed previously, Winyah is modeled to be retired in phases, with two of the four generation units being idled by the winter of 2021/2022 and all four units retired by 2027.
- **Retire All Coal Portfolios** – Under this retirement scenario, the Winyah Plant is retired as described above, and the Cross Plant is also retired, with Units 1 and 2 retired in 2030 and Units 3 and 4 retired in 2032.

Sensitivity Analysis

For the 2020 IRP, Santee Cooper prepared resource expansion analyses examining various resources options under a Base Case set of assumptions that depicts expected market and planning conditions. In addition, Santee Cooper evaluated how resource expansion plans might change with changes in market, regulatory, load, and renewable resource planning, as follows.

- **Higher/Lower Load Growth** – Higher and lower retail and wholesale loads by one standard deviation of expected load forecast error due to economic uncertainty
- **High Natural Gas and Economy Energy Prices** – 50 percent increase in natural gas prices and an associated increase in economy power prices for market purchases in all years
- **CO2 Tax** – $15 per ton price beginning in 2027, increasing annually by $5 per ton until a cap of $80 per ton is reached in 2040
- **Lower Level of Solar Resources** – Reduction in planned solar implementation by 500 megawatts

Specific assumptions utilized for the Base Case and each sensitivity case are discussed in more detail below and in the following section of the IRP Report.

For each sensitivity case, the CapEx model was allowed to optimize generation expansion portfolios specific to the assumptions for the case. Utilizing this approach, Santee Cooper was able to understand the variability of future power supply costs, recognize how resources expansion portfolios change for specific sensitivity assumptions, and identify whether specific resource expansion decisions were robust and would not change materially for changes in major assumptions.

Major Assumptions

The following section summarizes major assumptions for cost escalation, financial assumptions, fuel prices, and economy power prices. Assumptions are provided for Base Case and sensitivity cases and were developed in consultation with Central.

Cost Escalation

The IRP was prepared utilizing the assumptions for future annual cost escalation depicted in Table 6-1. Assumptions are based on recent long-term projections of general inflation and facility cost escalation derived from a variety of sources.

Table 6-1
Escalation Assumptions

Cost Category	Annual Escalation Rate
Fixed and Variable Operating Cost	2.0%
Capital Cost for New Generating Resources	2.5%
Capital Costs for New Electric Transmission Facilities	2.0%
Capital Costs for Natural Gas Pipeline Facilities	2.0%

The IRP utilizes a constant two percent annual cost escalation assumption across a broad range of operating costs, such as fixed and variable operation and maintenance costs and administrative costs. Cost escalation for generation equipment is generally based on trends in historical cost escalation published in the Handy-Whitman Index of Public Utility Construction Costs (HWI). Cost escalation for transmission equipment and natural gas pipeline equipment was tied to assumptions for general inflation.

Financial Assumptions

Financial cost assumptions utilized for the IRP, including the Santee Cooper cost of long-term and short-term debt and the discount rate utilized for purposes of presenting present value system power costs are provided in Table 6-2. These assumptions are based on information provided by Santee Cooper's financial advisors, PFM Financial Advisors, LLC.

Table 6-2
Study Financial Assumptions

Financial Assumption	Interest Rate
Long-term Debt Interest Rate	3.76%
Interest During Construction (utilizing Commercial Paper)	2.63%
Discount Rate for Present Value Calculations	3.76%

Load Forecast

The Load Forecast modeled for the 2020 IRP includes the Base Case assumptions described above in Section 4, as well as sensitivity case assumptions for higher and lower load growth that reflect uncertainty in future economic conditions. Central and Santee Cooper independently produced sensitivity case forecasts for the Central and Santee Cooper loads, respectively, reflecting one standard deviation of potential variation in load growth attributable to economic uncertainty. Table 6-3 provides the resulting aggregate system annual energy requirements and firm winter peak demand for the Base Case and the Low and High Load Cases.

Table 6-3
Load Forecast Scenarios

	Base Case		Low Load Case		High Load Case	
Year	Energy Require-ments	Winter Peak Demand	Energy Require-ments	Winter Peak Demand	Energy Require-ments	Winter Peak Demand
2021	23,897	4,933	23,308	4,820	24,930	5,057
2022	24,689	5,072	23,951	4,946	25,733	5,233
2023	24,706	5,101	23,722	4,927	25,786	5,278
2024	24,872	5,127	23,702	4,910	26,079	5,328
2025	24,776	5,140	23,611	4,931	26,306	5,419
2026	24,833	5,168	23,511	4,917	26,536	5,475
2027	24,874	5,187	23,411	4,906	26,770	5,534
2028	25,087	5,233	23,488	4,922	27,176	5,622
2029	24,936	5,145	23,195	4,803	27,224	5,575
2030	25,055	5,177	23,177	4,807	27,541	5,650
2031	25,196	5,210	23,178	4,810	27,879	5,725
2032	25,387	5,247	23,232	4,819	28,268	5,805
2033	25,500	5,281	23,205	4,825	28,589	5,885
2034	25,661	5,316	23,228	4,833	28,959	5,966
2035	25,822	5,353	23,250	4,841	29,332	6,049
2036	26,042	5,395	23,329	4,856	29,764	6,139
2037	26,173	5,433	23,319	4,865	30,117	6,226
2038	26,354	5,476	23,357	4,879	30,526	6,319
2039	26,543	5,520	23,402	4,894	30,968	6,418
Compound Avg. Growth Rates:						
2021-2039	0.6%	0.6%	0.0%	0.1%	1.2%	1.3%

Fuel Price Forecasts

Coal Price

Long-term forecasts for the delivered price of coal to the Cross and Winyah units were developed by Santee Cooper based on long-term basin price forecasts obtained from Energy Ventures Analysis (EVA) and S&P Global and rail transportation costs developed by Santee Cooper. Additionally, market pricing from ICAP is used for the estimation of coal pricing through 2023. Forecast rail transport costs were developed from recent experience of Santee Cooper and reflect near-term contract prices and long-term assumptions with annual cost escalation of 1.5 percent.

Sources of supply to Santee Cooper's coal units were assumed to include the Central Appalachian, Northern Appalachian, and Illinois Basins, with coal blends specific to each coal-fired generating resource. Figure 6-2 and Figure 6-3 depict the resulting projections of the delivered price of coal burned by unit at Cross and Winyah Station, respectively.

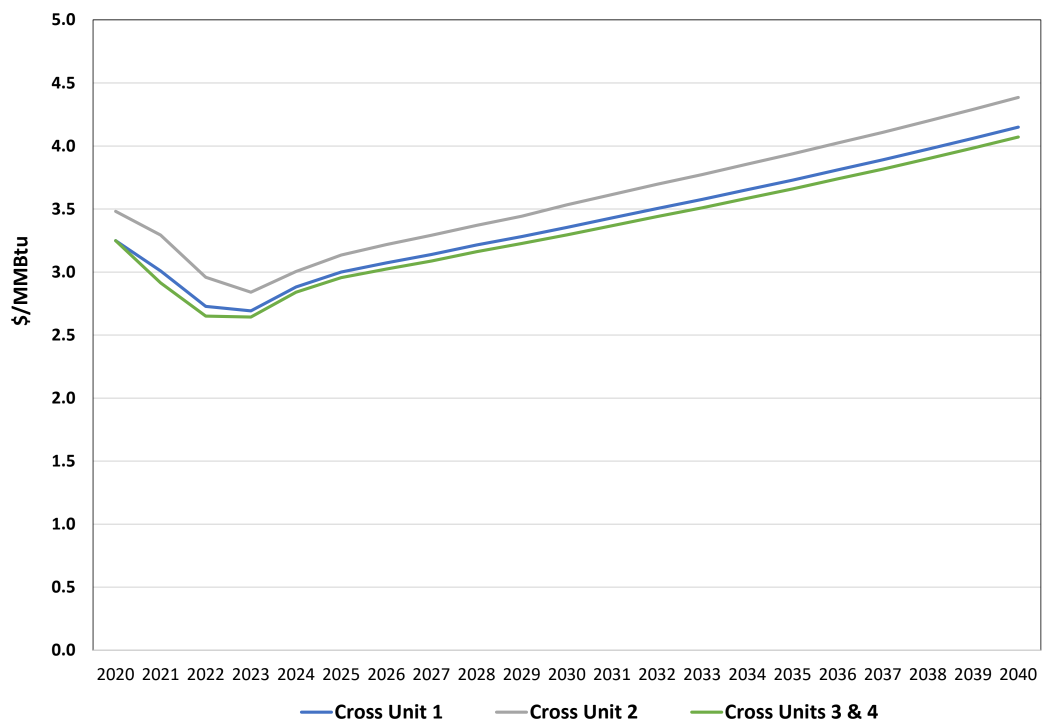

Figure 6-2: Projected Price of Coal Delivered to Cross Station

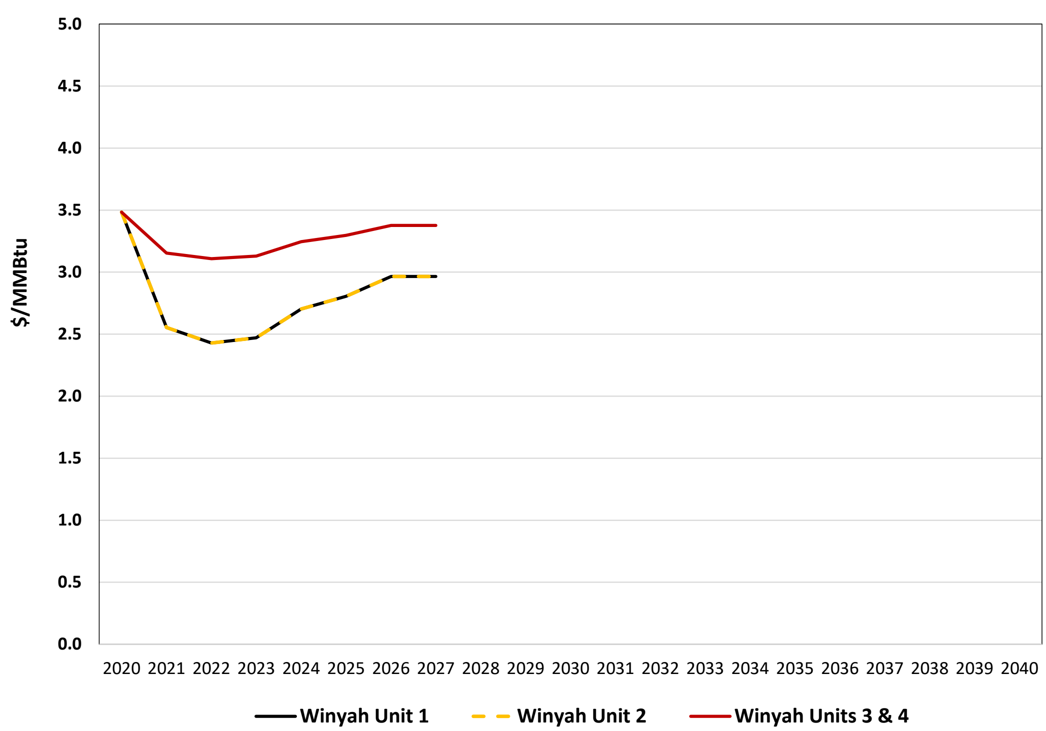

Figure 6-3: Projected Cost of Coal Delivered to Winyah Station

Natural Gas Commodity Price

Natural gas prices were developed based on an average of forecast and forward natural gas price curves for Henry Hub obtained from multiple sources. Santee Cooper utilized an average of forward NYMEX Henry Hub prices settled during the month of May 2020 published by S&P Global to provide a forecast through 2032. Beyond 2032, Santee Cooper utilized a fundamental forecast of Henry Hub prices through 2039 prepared by SNL and published S&P Global. Prices were modeled to transition uniformly from forward to forecast prices over a seven-year period through 2039. Prices beyond 2039 were escalated at the compound annual growth rate observed for the final three years of the forecast period. Figure 6-4 depicts the projected monthly nominal prices for Henry Hub assumed in the 2020 IRP for the Base Case.

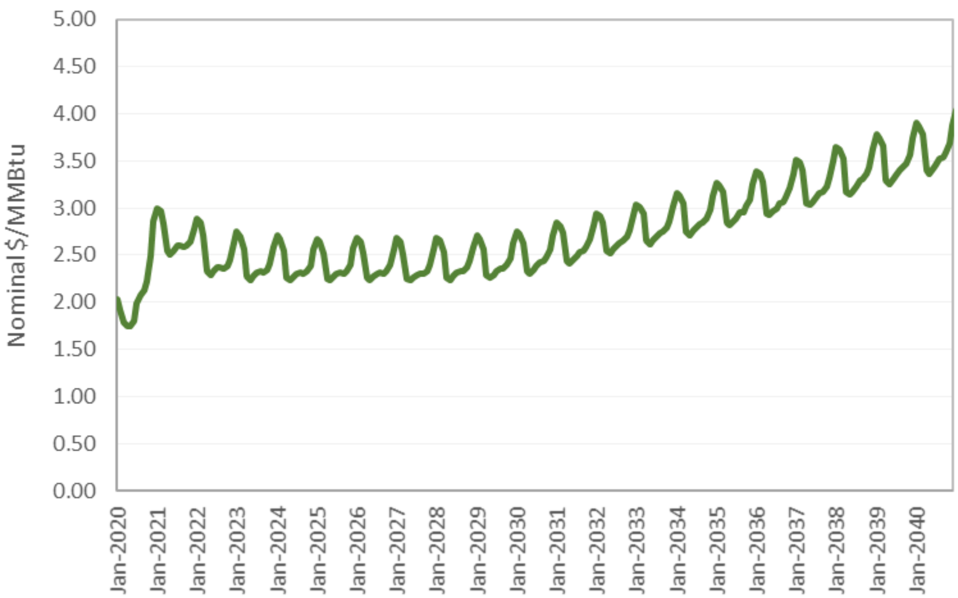

Figure 6-4: Projected Henry Hub Natural Gas Prices

In addition, a high natural gas price case (High NG Case) was developed to test the sensitivity of resource decisions and future power costs to higher gas prices. This High NG Case assumes Henry Hub prices are 50 percent higher than the Base Case forecast. Because natural gas price are near historically low levels, Santee Cooper did not model a low natural gas price scenario for the 2020 IRP. Figure 6-5, below, depicts the projected annual nominal prices for Henry Hub assumed in the 2020 IRP for the Base Case and the High NG Case.

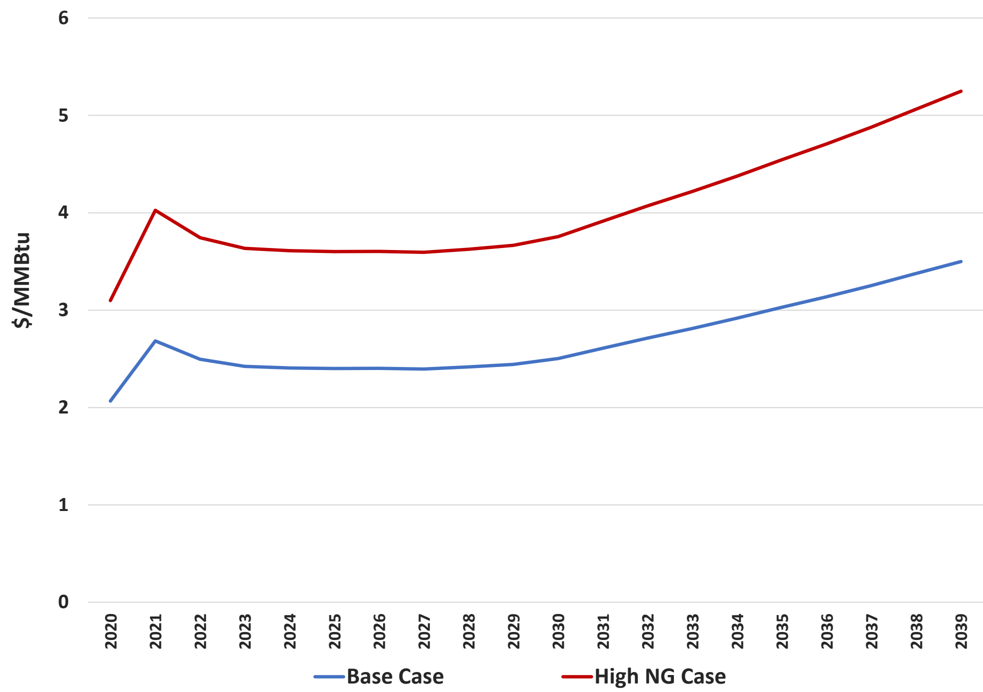

Figure 6-5: Projected Henry Hub High Natural Gas Price Sensitivity

Natural gas price basis differentials for natural gas hubs to which Santee Cooper has access (i.e., Transco Zone 4 and Transco Zone 5) were developed from the average of forecast hub prices prepared by OTC Global Holdings through 2029 and published by S&P Global during May 2020. The forecast monthly basis differentials were added to or subtracted from the forecast Henry Hub price utilized for the 2020 IRP, with basis pricing beyond 2029 held constant. Natural gas hub basis differentials were assumed to remain unchanged for the High NG Price sensitivity. Figure 6-6 depicts the forecast monthly natural gas hub basis assumed for the 2020 IRP. As depicted below, Transco Zone 5 is subject to the influence of much higher demand for natural gas as a heating fuel, primarily in the Northeast, during winter months.

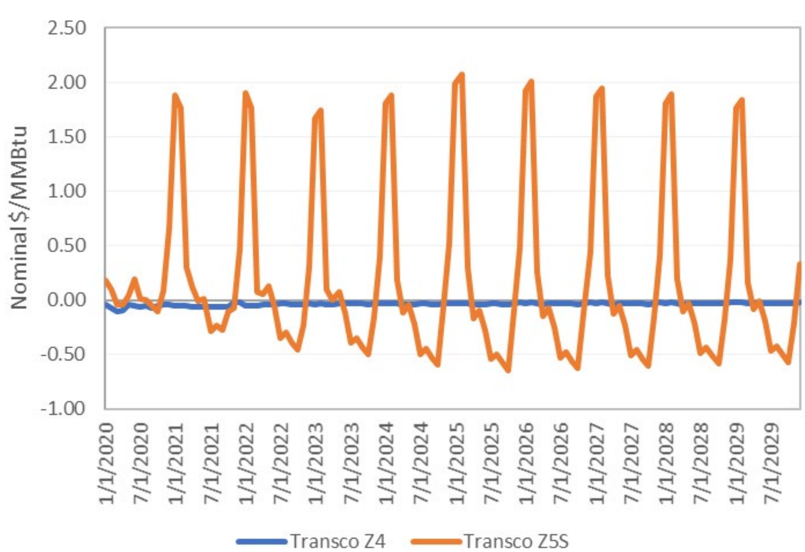

Figure 6-6: Projected Natural Gas Price Basis

Natural Gas Transportation

Costs for natural gas transportation were added to the forecast natural gas commodity and hub basis prices to develop delivered prices of natural gas modeled for existing and future natural gas-fired resources. Variable transportation charges (i.e., fuel use charges and variable transportation service rates and fees) were added to the delivered cost for all natural gas-fired resources. Natural gas-fired combined cycle (NGCC) resources were modeled with firm natural gas transportation service (FT service), while natural gas-fired combined cycle (NGCT) peaking resources were generally modeled using interruptible natural gas transportation service (IT service).

Use of FT service for base-loaded NGCC resources is important to assure resource capacity can be counted as firm. NGCT resources, which typically operate at low capacity factors, were modeled as having diesel fuel backup and assumed to not require FT service to assure firm capacity and instead were modeled to use IT service. Additionally, in certain instances when a portfolio might consider only new NGCT resources for expansion at a site without preexisting natural gas service, firm NG transportation service was modeled to reflect the cost of securing new pipeline facilities to the site. Where appropriate, existing Santee Cooper natural gas-fired resources were modeled assuming existing fuel supply contracts, converting to more general market assumptions following existing contract terms.

The projected price of transportation service was developed for each potential NGCC site and delivery configuration based on rate information obtained from natural gas pipeline companies and from existing pipeline tariffs. Charges for FT service were assumed to vary for the evaluated NGCC generation sites based on the proximity of each site to interstate pipelines in the region. For instance, charges for FT service at the Winyah Generating Station were assumed to be approximately twice that assumed for a site near the V. C. Summer Generating Station. Additionally, charges for FT service were assumed to decline with increasing volumes to reflect improved economy of scale associated with larger pipeline lateral installations. FT service was modeled as a fixed cost for each NGCC resource within the CapEx model by multiplying the max hourly natural gas requirement by the firm reservation charge. IT service was assumed to be equal to the firm reservation charge but was assigned as a variable cost adder to the delivered price of natural gas. Natural gas transportation charges were assumed to remain constant over the IRP study period.

Nuclear Fuel

The projected cost of nuclear fuel at the V. C. Summer Generating Station was provided by Dominion through 2029 and escalated thereafter at the average rate computed over 2022-2029. Figure 6-7, below, depicts the projected cost of nuclear fuel at Summer over the study period.

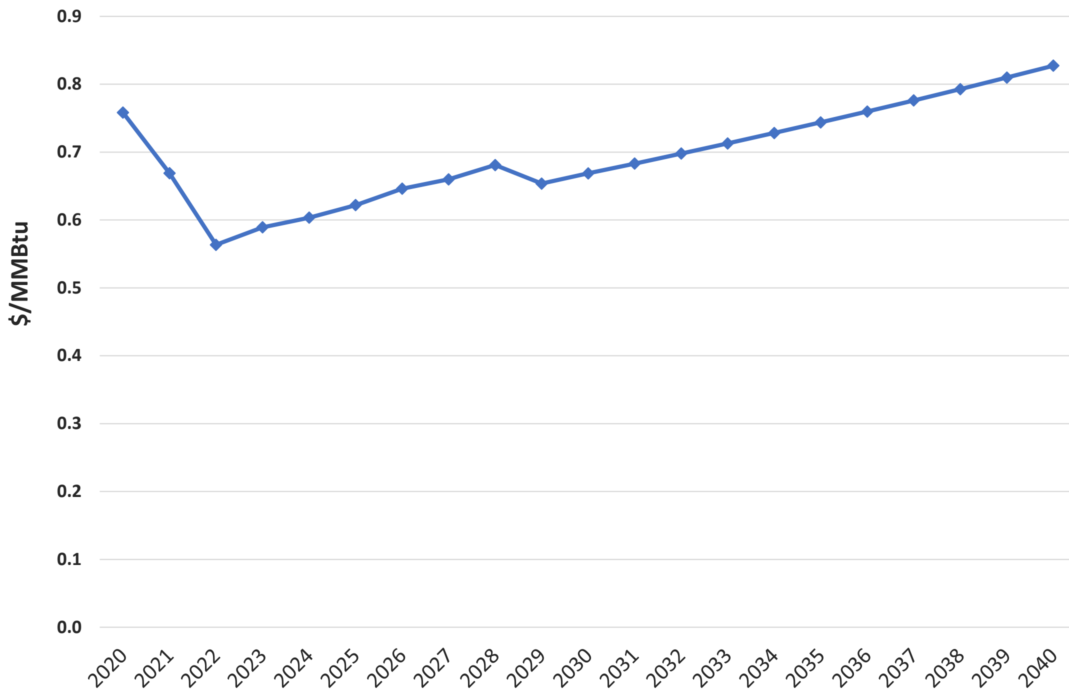

Figure 6-7: Projected Nuclear Fuel Cost at V.C. Summer

Power Market Prices

The IRP assumes that Santee Cooper has access to economy energy purchases from the market as an additional resource to economically meet load requirements. Economy energy reflects daily and short-term purchases, with prices varying monthly with natural gas prices and daily based on assumed market conditions. Pricing includes two tiers: Tier 1 for economy purchases that are generally available year-round across all hours, and Tier 2 depicting additional amounts assumed available at a price premium, and with the modeled quantity of either tier being dependent on the economic dispatch simulated in the CapEx model. See the section entitled Transmission System Considerations, below, for additional information on modeled economy import limits.

The projected price of Tier 1 economy energy purchases is based on projections of monthly energy market prices developed by The Energy Authority (TEA) for the Southern Company market area, adjusted to be consistent with the Henry Hub prices modeled for the 2020 IRP, utilizing an implied monthly heat rate from TEA projections. TEA projections were based on market indicators, including market offers, forward prices for power and natural gas, and fundamental forecasts of power prices and natural gas prices. Projected economy energy prices are further adjusted for assumed wheeling charges to reach the Santee Cooper interface, and to reflect typical daily price volatility relative to variations in load. Tier 2 economy energy prices assume a 15 percent price premium relative to Tier 1.

Figure 6-8, below, depicts the economy energy prices modeled for the 2020 IRP under the Base Case. Economy energy prices were also modeled for the High NG Price sensitivity case utilizing the implied heat rate and other adjustments described above for the Base Case forecast. Figure 6-9, below, depicts the projections of the economy energy prices under the Base Case and High NG Price sensitivity case.

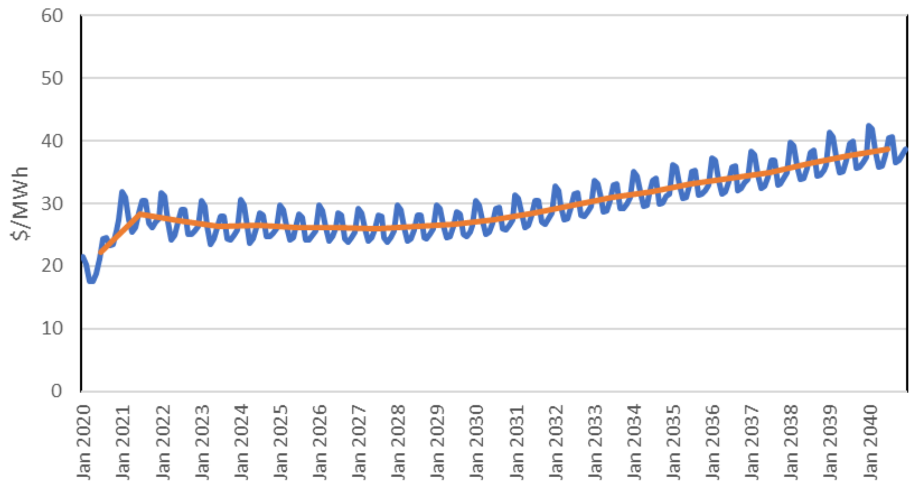

Figure 6-8: Projected Base Case Tier 1 Monthly Economy Energy Price

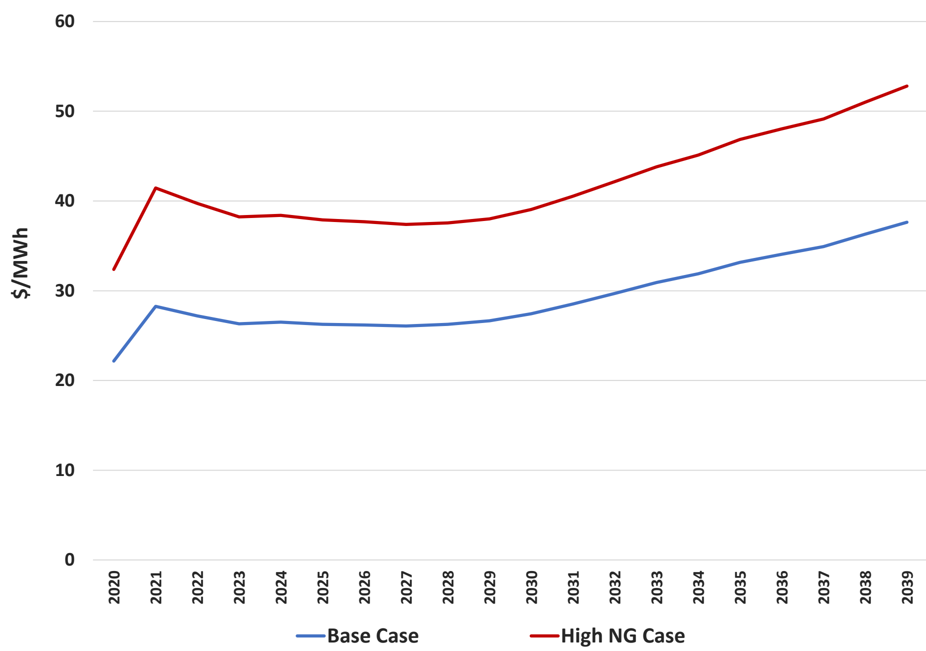

Figure 6-9: Projected Annual Base Case and High Prices for Economy Energy

Existing Santee Cooper Resources

Santee Cooper currently owns and operates approximately 5,338 megawatts (winter rating) of generating resources and purchases approximately 471 megawatts from other parties. Table 6-4, below, lists existing generation resources owned by Santee Cooper, including information on resource location, in-service date, winter and summer capacity ratings, and the fuel or energy source. Table 6-5, below, lists existing and planned wholesale purchases made by Santee Cooper, including information on the type of resource, purchase term, nameplate capacity rating, and winter and summer firm capacity ratings.

Table 6-4
Existing Santee Cooper Generation Resources

Generating Facilities	Location	In Service Date	Winter MCR(1) (MW)	Summer MCR(1) (MW)	Energy Source
Jefferies Hydroelectric Generating Station(2)	Moncks Corner	1942	140	140	Hydro
Wilson Dam Generating Station	Lake Marion	1950	2	2	Hydro
Myrtle Beach CT1-CT5	Myrtle Beach	1962-1976	65	56	Oil/NG
Hilton Head CT1-CT3	Hilton Head	1973-1979	100	88	Oil
Winyah Generating Station	Georgetown				
No. 1		1975	280	275	Coal
No. 2		1977	290	285	Coal
No. 3		1980	290	285	Coal
No. 4		1981	290	285	Coal
Summer Nuclear Unit 1	Jenkinsville	1983	322	322	Nuclear
Cross Generating Station	Cross				
Unit 1		1995	585	580	Coal
Unit 2		1983	570	565	Coal
Unit 3		2007	610	610	Coal
Unit 4		2008	615	615	Coal
Landfill Gas Resources					
Horry Landfill Gas Station	Conway	2001	3	3	LFG
Lee County Landfill Gas Station	Bishopville	2005	11	11	LFG
Richland County Landfill Gas Station	Elgin	2006	8	8	LFG
Anderson County Landfill Gas Station	Belton	2008	3	3	LFG
Georgetown County Landfill Gas Station	Georgetown	2010	1	1	LFG
Berkeley County Landfill Gas Station	Moncks Corner	2011	3	3	LFG
Rainey Generating Station	Starr				
Unit 1		2002	520	460	NG
Unit 2A		2002	180	146	NG
Unit 2B		2002	180	146	NG
Unit 3		2004	90	75	NG
Unit 4		2004	90	75	NG
Unit 5		2004	90	75	NG
Total Capability (3)			5,338	5,110	

(1) Maximum Continuous Ratings (MCR).
(2) MCR updated after Hydro rebuilds.
(3) Santee Cooper currently owns 5.1 megawatts of solar resources that do not contribute to the total capability.

While Santee Cooper has announced its intent to retire the Winyah Generating Station, as discussed below, Santee Cooper has not otherwise assigned useful life estimates to other generating resources. For purposes of the 2020 IRP, Santee Cooper has assumed that standard maintenance on the existing generating assets will permit the continued operation of the resources through the IRP study period. Santee Cooper intends to periodically study the economics of retirement of its generating assets, including the Cross retirement portfolios detailed herein. See Appendix B for additional information related to environmental compliance planning for existing resources.

Table 6-5
Existing Santee Cooper Purchases

Generating Facilities	Term	Nameplate Capacity (MW)	MCR (MW)	Energy Source
Buzzards Roost	March 2020	15	8	Hydro
Domtar	2025	38	38	Biomass
EDF Renewables	2043	36	36	Biomass
Southeastern Power Administration	Indefinite	305	305	Hydro
St. Stephens Hydro(1)	2035	84	84	Hydro
TIG Solar(2)	2033	3	0	Solar
Total		481	471	

(1) Santee Cooper anticipates taking ownership of St. Stephens by 2035.
(2) The MCR for TIG Solar is 0 because the Santee Cooper winter peak typically occurs early in the morning before PV production would occur.

Winyah Generating Station Retirement

Santee Cooper has announced its intent to retire Winyah Generating Station in a phased manner over 2021-2027. Current plans call for Winyah Unit 4 to be idled in the winter of 2020/2021, followed by Winyah Unit 3 in the winter of 2021/2022, with the entire generating station being retired by 2027. Santee Cooper continues to evaluate the appropriate timing for the idling of Winyah Units 3 and 4 with consideration of uncertain territorial loads, economies of operation and idling, and technical requirements to idle the generating facilities. Santee Cooper has developed a staffing plan for the Winyah Generating Station and has begun staff reduction efforts. Additionally, future maintenance outage plans and schedules are being modified to accommodate the planned retirement.

Gypsum Delivery Contracts

Santee Cooper has contracted with American Gypsum (AG) to deliver quantities of gypsum, produced as a byproduct of emissions control processes at Santee Cooper's coal plants. Gypsum is a byproduct of the flue gas desulfurization process utilized at Santee Cooper's coal plants to reduce sulfur content in air emissions from these plants and is utilized by AG to produce gypsum wallboard at an AG manufacturing facility located adjacent to the Winyah site. To the extent the coal plants do not produce enough wallboard quality gypsum to meet minimum required deliveries under the AG contract, Santee Cooper fulfills any shortfalls by purchasing gypsum in the open market for delivery to the AG site. Gypsum produced at the Cross plant is shipped by Santee Cooper to the AG site through 2028. Beginning in 2029, AG takes ownership of Cross-produced gypsum at the Cross site.

The IRP reflects gypsum production from the coal units based on historical production rates. Remaining gypsum requirements to satisfy the AG contract are assumed in this IRP to be fulfilled via market purchases at an assumed cost rate of $46 per ton, escalated at the general inflation rate.

Summer Nuclear Station Licensing

In 2004, the Nuclear Reliability Commission (NRC) extended the operating license for Summer Nuclear Unit 1 to August 6, 2042, an additional twenty years beyond the then-current operating license period.

FERC Hydro Licensing

Santee Cooper operates its Jefferies Hydro Station and certain other property, including the Pinopolis Dam on the Cooper River and the Santee Dam on the Santee River, which are major parts of Santee Cooper's integrated hydroelectric complex, under a license issued by the Federal Energy Regulatory Commission (FERC) pursuant to the Federal Power Act (FPA). The FERC license includes oversight of project activities such as Dams and Dikes Maintenance, Shoreline Management, Forestry Management, Mosquito Control, Water Quality Monitoring, and Aquatic Plant Management, conducted in cooperation and partnership with DHEC, the South Carolina Department of National Resources (the DNR), the U.S. Fish and Wildlife Service (USFWS), and the National Marine Fishery Service (NMFS). The project is currently undergoing relicensing and a Notice of Intent (NOI) to relicense was filed with the FERC on November 13, 2000. The final license application was submitted March 12, 2004. Due to a number of Additional Information Requests, the relicensing process has extended beyond the license expiration date. The FERC has issued a standing annual license renewal until a final license is issued.

The FERC issued its Final Environmental Impact Statement (EIS) in October 2007. The DNR, the USFWS and Santee Cooper jointly signed and filed a settlement agreement in May 2007 with the FERC that among other things, identifies fish passage and outflow guidelines during the term of the next license. The NMFS chose not to join in the settlement agreement and in January 2020 submitted final documents for mandatory fishway conditions under Section §18 of the FPA, flow recommendations under Section §10 of that Act, and a biological opinion for endangered Shortnose and Atlantic sturgeon under Section 7 of the Endangered Species Act (ESA). Santee Cooper is finalizing an engineering assessment of the impacts higher outflows prescribed by NMFS will have to the Santee Dam system. Santee Cooper cannot predict the final scope, timing, or general outcome of the FERC relicensing process.

Supply-Demand Balance

Combining projections for the Load Forecast, existing resource capabilities, and planned phased retirement of the Winyah Generating Station yields projections of the future Santee Cooper supply-demand balance as depicted in the following Figure 6-10 and Table 6-6, below. Supply resources reflected below include only existing owned and purchased resources. Some small amounts of capacity are needed over 2022 through 2026, but the first major capacity need is triggered by the full retirement of Winyah in 2027, at which time the Santee Cooper system will be short approximately 700 megawatts. As described more fully below, Santee Cooper is planning to meet capacity needs in the near-term with new quick-start peaking resources, battery storage resources, demand response programs, and short-term capacity purchases. Longer-term capacity requirements have been identified through the 2020 IRP by determining the most economic combination of resources to meet Santee Cooper's load obligations over this 20-year planning horizon while balancing the objectives of the Santee Cooper planning process.

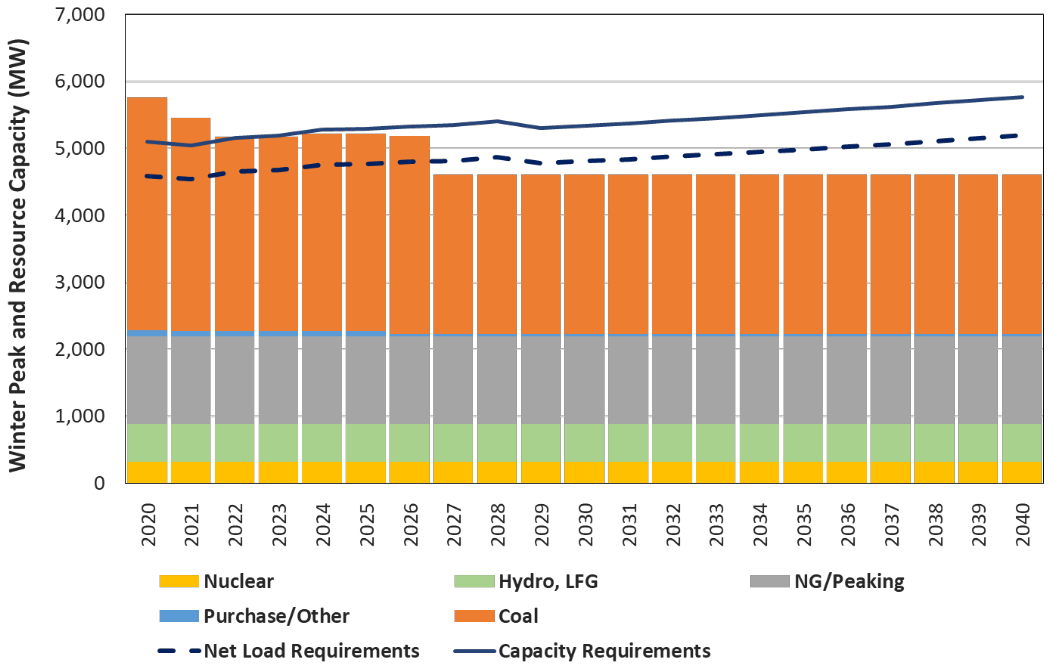

Figure 6-10: Santee Cooper System Supply and Demand Balance

Table 6-6
Santee Cooper System Supply and Demand Balance

Load & Resources	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
System Demand																					
Winter Peak Demand	4,951	4,932	5,071	5,101	5,127	5,140	5,168	5,187	5,233	5,145	5,177	5,210	5,247	5,281	5,316	5,353	5,395	5,433	5,476	5,520	5,561
Less: Non-firm/Interruptible Loads	(308)	(339)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(370)	(370)
Less: Non-system Wholesale Sales	(52)	(52)	(52)	(52)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less: Firm Hydro Resources	(389)	(389)	(389)	(389)	(389)	(389)	(389)	(389)	(389)	(389)	(389)	(389)	(389)	(389)	(389)	(389)	(389)	(389)	(389)	(389)	(389)
Net Peak Demand	4,202	4,152	4,260	4,290	4,368	4,381	4,409	4,428	4,474	4,386	4,418	4,451	4,488	4,522	4,557	4,594	4,636	4,674	4,717	4,761	4,802
Resource Capacity																					
Existing Resources																					
Coal Steam	3,530	3,240	2,950	2,950	2,950	2,950	2,950	2,380	2,380	2,380	2,380	2,380	2,380	2,380	2,380	2,380	2,380	2,380	2,380	2,380	2,380
Nuclear	322	322	322	322	322	322	322	322	322	322	322	322	322	322	322	322	322	322	322	322	322
NGCC/NGCT	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150
Peaking	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165
Landfill Gas	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29
Hydro	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142
Purchases	89	74	74	74	74	74	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
Total	5,427	5,122	4,832	4,832	4,832	4,832	4,794	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224
Less: Unit-contingent Sales	(52)	(52)	(52)	(52)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Net Capacity	5,375	5,070	4,780	4,780	4,832	4,832	4,794	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224
Capacity Reserves																					
Net Peak Demand	4,202	4,152	4,260	4,290	4,368	4,381	4,409	4,428	4,474	4,386	4,418	4,451	4,488	4,522	4,557	4,594	4,636	4,674	4,717	4,761	4,802
Planning Reserves (12%)	504	498	511	515	524	526	529	531	537	526	530	534	539	543	547	551	556	561	566	571	576
Total Capacity Requirements	4,707	4,650	4,771	4,805	4,892	4,907	4,938	4,959	5,011	4,912	4,948	4,985	5,026	5,065	5,104	5,145	5,192	5,235	5,283	5,332	5,378
Total Net Capacity	5,375	5,070	4,780	4,780	4,832	4,832	4,794	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224
Capacity Surplus/(Deficiency)	668	419	9	(25)	(60)	(75)	(145)	(736)	(787)	(688)	(725)	(761)	(803)	(841)	(881)	(921)	(969)	(1,011)	(1,059)	(1,108)	(1,154)

Supply-side Options

Conventional Thermal Resource Options

Cost and operating characteristics of potential NGCC, NGCT, and aero-derivative gas turbine resource options were developed jointly by Santee Cooper and Central. Sources of these estimates included a variety of publicly available reports, original equipment manufacturer estimates, and proprietary databases and estimates developed by consultants for Central and Santee Cooper. Capital costs, operating costs, and operating characteristics were developed for two-on-one (2x1) H-class NGCC resources, both with and without duct-firing (DF), and for single H-class NGCT resources. Table 6-7 provides the capital costs, average ambient capacity rating, fixed and variable operating and maintenance (O&M) costs, and heat rate characteristics that were assumed for conventional, fossil-fueled resource options.

Table 6-7
Operating Costs and Characteristics of Conventional Resource Options

	2x1 NGCC (no DF)	2x1 NGCC (with DF)	NGCT	LM2500
Total Project Cost ($M)	665.9	697.8	196.0	31.3
Max Rating (MW, ambient)	1,104.6	1,315.2	347.9	32.3
Per Unit Cost ($/kW)	602.82	530.59	563.39	970.33
Operating Cost				
Fixed O&M ($/kW-yr)	5.07	4.26	5.46	26.00
Variable O&M ($/MWh)	3.34	3.16	8.73	12.68
Full Load Heat Rate (Btu/kWh)	6,110	6,383	9,200	9,680

For purposes of the 2020 IRP, Santee Cooper evaluated options to build 2x1 NGCC resources, as depicted in Table 6-7, as well as options that assume NGCC additions could be developed jointly with other parties, with Santee Cooper retaining an entitlement to one-half of the unit, thereby permitting Santee Cooper to take advantage of improved economies of scale of the larger NGCC while attaining a resource that fits into Santee Cooper's resource portfolio and resource planning more effectively. For these jointly developed units, it was assumed that Santee Cooper would be entitled to one-half of the unit's capacity and energy output and be responsible for one-half of the development, construction, and operating cost of the unit, including the cost of transmission upgrades and firm natural gas service.

Solar Resources

The IRP assumes that Santee Cooper would contract for solar power from utility-scale solar facilities developed, owned, and operated by private developers through purchase power agreements (PPA). Under such PPAs, the Seller would be responsible over the life of the project for operating, maintaining, and decommissioning its project. This approach would enable Santee Cooper to reduce energy costs and financial risk by avoiding on-balance sheet debt. It is expected that owners of these projects will monetize the tax incentives available to solar projects and pass on the benefit to Santee Cooper through lower PPA pricing given the competitive nature of the procurement.

Under the Base Case, energy delivered under such solar PPAs are assumed at a long-term, fixed rate of $25 per megawatt-hour, inclusive of transmission interconnection costs. This assumption is based on Santee Cooper experience and market knowledge gained primarily through recent competitive procurement processes. On October 15, 2019, Santee Cooper issued a Request for Information (RFI) from potential solar resource developers, and on June 5, 2020, Santee Cooper issued a Request for Proposals for Solar Power, to which responses are currently under evaluation. Responses to both the RFI and the RFP indicate that a price of $25 per megawatt-hour is indicative of current market prices for solar energy. The 2020 IRP assumes that continued downward cost pressure for PV modules and balance of plant equipment will be sufficient to offset the effects of declining investment tax credits over the next several years. The IRP assumes further that such contracts could be renewed or replaced at the end of their terms, which typically span 15-25 years, and facility refurbishments made to extend the lives of the solar facilities for approximately the same pricing in nominal terms throughout the study period.

Solar facilities would be located near Santee Cooper's primary load centers near the coast but would be geographically dispersed to achieve production diversity while maintaining significant economies of scale. As Santee Cooper is winter peaking, with the peak typically occurring during the hour ending 8 AM, solar capacity would not contribute to meeting peak demand requirements. While some capacity value could be achieved toward meeting the summer peak, which typically occurs in the late afternoon, this IRP does not reflect any capacity value for solar resources.

Santee Cooper expects to execute multiple PPAs for solar resources to provide for an initial tranche of 500 megawatts of nameplate capacity though solar PPAs. The 2020 IRP reflects that an additional 1000 megawatts of solar resources will be secured over 2023-2032 period. The capacity factor of the solar resources is assumed to be approximately 28 percent, based on the estimated typical output of single-axis tracking solar resources in or near the Santee Cooper system. Table 6-8, below, provides the cumulative solar resources procured in addition to Santee Cooper's existing solar resources discussed earlier in this section under the heading, Existing Santee Cooper Resources.

Table 6-8
Solar Implementation Schedule Assumed for the IRP

Year	Nameplate Capacity (MW)
2020	0
2021	75
2022	150
2023	500
2024	555
2025	800
2026	1,000
2027	1,000
2028	1,000
2029	1,250
2030	1,350
2031	1,425
2032+	1,500

Storage Resources

The 2020 IRP assumes that Santee Cooper will add battery energy storage systems (BESS) with a total capacity of 200 megawatts in 50 megawatt increments over the 2026-2036 timeframe. These BESS systems are assumed to have two-hour storage capability, primarily targeting the Santee Cooper winter peak demand and transmission reliability requirements. Utilization of BESS with low frequency of charge/discharge cycles allows for the useful life of the units to extend through the 2020 IRP study period and is consistent with relatively low operation and maintenance costs. Table 6-9 provides the cumulative BESS capacity assumed to be implemented in all resource portfolio analyses discussed herein.

Table 6-9
BESS Implementation Schedule Assumed for the IRP

Year	Nameplate Capacity (MW)
2020-2025	0
2026	50
2027	50
2028	50
2029	50
2030	50
2031	50
2032	50
2033	100
2034	100
2035	150
2036+	200

Capital and O&M costs for BESS were jointly developed by Santee Cooper and Central based on information obtained from battery system vendors, public reports by other industry organizations, and indications from renewable resource procurement process. Cost and operating characteristics were developed for both two- and four-hour BESS for evaluation in the 2020 IRP. Initial results indicated that a BESS system with two-hours of storage would be more cost effective than a four-hour system. However, Santee Cooper recognizes the limitations of modeling BESS in the CapEx model and intends to further study BESS economics, including the operation of longer duration BESS to manage seasonal peak demand periods, intermittent resource operation, and energy arbitrage.

Figure 6-11 depicts the assumed capital cost on a unit energy capacity basis of two-hour and four-hour BESS over the study period. Fixed O&M is assumed at $3 per kilowatt-year in 2020 dollars, with escalation at 2.0 percent per year.

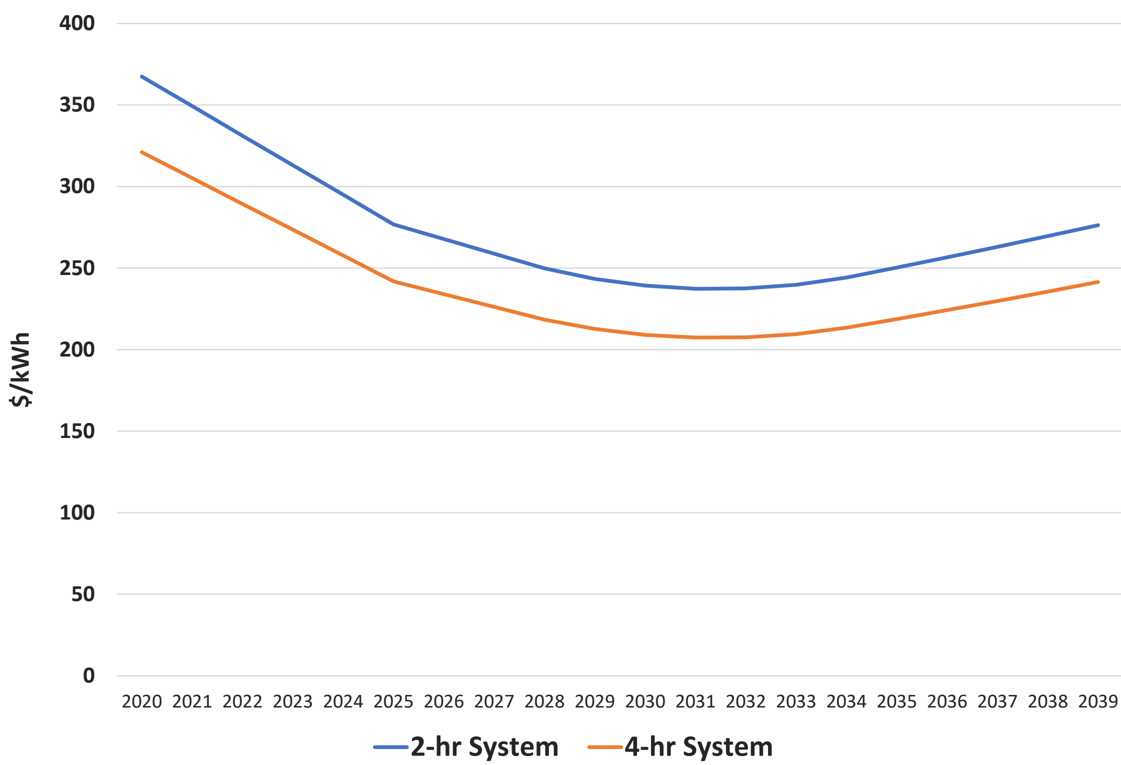

Figure 6-11: Projected Trend of Two-Hour Battery System Capital Costs

Demand-side Resources

Santee Cooper and Central have conducted DSM programs aimed at improving the efficiency of residential and commercial end uses for many years, as discussed in Section 4 above. Central also has a variety of load management measures in place across its member cooperatives. The Load Forecast utilized for this IRP reflects the latest projections of the level of activity and impacts of these programs through reductions in future peak demand and energy requirements.

In addition, the IRP assumes the implementation of demand response programs by Santee Cooper and Central targeting peak demands and offsetting demand requirements that must otherwise be met by supply-side resources. This includes the development of a program to control air conditioning units and water heaters at residential and commercial customers on the Santee Cooper distribution system to reduce demand for electricity. Santee Cooper is currently undertaking a process to obtain interest and information from vendors regarding potential program costs, technologies, and logistics. Santee Cooper's projected DR capability also includes both conservation voltage reduction and Volt-VAR optimization across the Santee Cooper system, programs which have recently been under development. This measure is intended to reduce system losses and peak demand through improving voltage stability across the system and reducing voltage slightly during peak periods. The IRP also reflects the implementation and expansion of similar measures by Central. The projected incremental DR program capability is provided in Table 6-10.

Table 6-10
Projected Demand Response Program Capability
Megawatts

	Santee Cooper System				
Year	Direct Load Control	Conservation Voltage Reduction and Other	Total	Central System	Total Capability
2020	0.0	18.0	18.0	0.0	18.0
2021	3.0	18.0	21.0	3.0	24.0
2022	7.2	18.0	25.2	5.0	30.2
2023	12.8	18.0	30.8	7.0	37.8
2024	18.5	18.0	36.5	12.0	48.5
2025	24.1	18.0	42.1	16.0	58.1
2026	29.7	20.2	49.9	20.0	69.9
2027	35.3	25.6	60.9	24.0	84.9
2028	39.2	25.6	64.8	27.0	91.8
2029	41.0	25.6	66.6	30.0	96.6
2030	42.3	25.6	67.9	33.0	100.9
2031	42.9	25.6	68.5	34.0	102.5
2032	43.4	25.6	69.0	35.0	104.0
2033	43.9	25.6	69.5	36.0	105.5
2034	44.3	25.6	69.9	36.0	105.9

Santee Cooper has developed projections regarding the capital and operating costs of implementing and sustaining the program, including equipment costs, initial and continuing participant incentives, and on-going costs related to marketing, call center operations, system licensing, communication fees, and administrative costs. These costs are included in the power costs reflected in the results presented herein. These DR program impacts are not reflected in the Load Forecast but are instead modeled as supply-side resource in the 2020 IRP.